DIRECT TESTIMONY OF
MARGOT EVERETT
ON BEHALF OF
DOMINION ENERGY SOUTH CAROLINA, INC.
DOCKET NO. 2020-229-E

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Margot Everett. My business address is 101 California Street, Suite 4100, San Francisco, California 94111. I am a Director for Guidehouse and will provide testimony on behalf of Dominion Energy South Carolina, Inc. ("DESC").

Q. BRIEFLY STATE YOUR EDUCATION, BACKGROUND, AND EXPERIENCE.

A. I have a Master of Science and Bachelor of Arts in Applied Economics from University of California, Santa Cruz. With over thirty-five years in the energy industry, I have held many differing roles from evaluation and design of customer programs, wholesale power contract structuring, market, credit and enterprise risk management and cost of service and rate design. Recently I spent five years leading Pacific Gas and Electric's (PG&E's) electric and gas rates, load forecasting and cost of service departments. In that role I have led the development and design of alternative rate designs for distributed energy resources, such as a successor to the Net Energy Metering ("NEM") successor tariff.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA (THE "COMMISSION")?

A. Yes, I testified on behalf of DESC in Docket No. 2019-182-E. I have also testified numerous times in California, and in particular on rate design policy and alternative rate designs. Further I supervised all testimony related to rates, cost of service and load forecasting for the five years I served as Senior Director of Rates and Regulatory Analytics at PG&E.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is twofold: to explain the current NEM tariff structure and associated estimated cost shift, and present the details of the design of the new NEM tariffs that DESC is proposing in this docket (the "Solar Choice Tariffs"). As part of my explanation of the Solar Choice Tariffs, I will address the resulting implications of the tariffs on the current cost shifts to non-NEM customers.

Q. PLEASE EXPLAIN YOUR PARTICIPATION IN THE GENERIC DOCKET (DOCKET NO. 2019-182-E).

A. I sponsored testimony for DESC. The purpose of my testimony was threefold. First, I sponsored testimony regarding the value of solar methodology currently used, proposed changes to that methodology, and the current value of solar estimates. Second, I presented the required cost-benefit analysis of the current NEM program (the "Current NEM Program") as required in the Generic Docket. This cost-benefit analysis included a review of the Current NEM Program as well as the cost-effectiveness of the current tariff design going forward. Finally, I presented best practices in the industry for both value of solar methodologies and NEM tariff structures.

I also provided responsive testimony that further discussed the appropriate treatment of benefits and costs in evaluating the Current NEM Program and explained high-level considerations for new Solar Choice tariff structures.

Q. PLEASE PROVIDE A HIGH-LEVEL OVERVIEW OF THE LESSONS LEARNED FROM THE COST-BENEFIT ANALYSES PERFORMED WITH REGARD TO THE CURRENT NEM PROGRAMS IN THE GENERIC DOCKET.

A. The results of the cost-benefit analyses of the Current NEM Program is that the program provides significant benefits to participants which in turn result in a measurable cost shift to non-participants. Table 1 below shows the results of the cost-benefit tests presented in the Generic Docket.

Table 1: Net Benefit Results by Sector (Annualized $/kWh)

	Sector	Participant Cost Test (PCT)	Utility Cost Test (UCT)	Rate Impact Measure (RIM)	Total Resource Cost Test (TRC)
Col Row		A	B	C	D
1	Residential	0.11726	0.00000	-0.09112	-0.07655
2	Small General Service	0.07260	0.00000	-0.08337	-0.01839

As Table 1 shows, the participant receives a benefit (the Participant Cost Test in Table 1) equal to about 11.7 cents per kWh of solar generation over a twenty-year life of the system. For small general service customers this value is slightly lower at 7.3 cents per kWh. However, this benefit results in a significant cost shift to non-participating customers (represented by the Rate Impact Measure in Table 1), with residential customers picking up 9.1 cents per kWh of additional costs for the generation produced over a twenty-year life, while small general service customers pick up an additional 8.3 cents per kWh for generation produced over a twenty-year life.

Additionally, from the review of best practices in NEM programs in the Generic Docket, several key rate features could help alleviate the magnitude of the cost-shift in accordance with S.C. Act No. 62 of 2019 ("Act 62"), including:

- Time differentiated Rates, which are rates that vary by time of day and season to reflect how certain costs vary.
- Net Billing, which typically means netting intervals of one hour or less. Under Net Billing, customers avoid retail rates for energy they consume behind the meter and are compensated separately for the exports. Many states, such as Hawaii, Arizona Alabama, Indiana, and New Hampshire, have moved from NEM to net billing. A study by GRIDWORKS titled "Sustaining Solar Beyond Net Metering: How Customer Owned Solar Compensation Can Evolve in Support of Decarbonizing California" (January 2018) noted that that Net Billing was an improvement to NEM with respect to several criteria, including providing customer choice, advancing decarbonization, and recovering grid costs.
- Fixed Charges, Demand Charges and Minimum Bills, which in concert, ensure the proper collection of fixed costs attributed to the customer-generator.

Q. PLEASE EXPLAIN DESC'S KEY CONSIDERATIONS AND GOALS IN DEVELOPING THE PROPOSED SOLAR CHOICE TARIFFS.

A. DESC's key considerations and goals in developing the proposed Solar Choice Tariffs were:

- First, the Solar Choice Tariffs must comply with Act 62. Specifically, the final rate design should eliminate cost-shift to the "greatest extent practicable on customers who do not have customer-sited generation while also ensuring customer-generator options for customers who choose to enroll in customer-generator programs. "[1] Additionally, Act 62 mandates that the Solar Choice Tariffs must "permit solar choice customer-generators to use customer-generated energy behind the meter without penalty."[2]
- Second, DESC wants to not only ensure continued promotion of innovation, but also avoid stifling other technologies that could address the same system needs more efficiently.
- Third, DESC wants a rate that is easy for customers to understand and which sends meaningful and actionable price signals to ensure the customer makes sound investments that provide them with clear savings, at minimal expense to non-participating customers.
- Finally DESC desires a rate that separates the costs to serve from incentives to create transparency of any subsidies that are included to support.

CURRENT NEM RATE DESIGN

Q. PLEASE DESCRIBE THE CURRENT NEM RATE DESIGN.

---

[1] S.C. Code Ann. § 58-40-20-(G)(1).
[2] S.C. Code Ann. § 58-40-20-(G)(2).

A. The current NEM structure allows for customers to consume generation from a behind-the-meter system and export the unused generation to DESC. DESC continues to provide load services at the available retail rate (e.g., Rate 8 for residential and Rate 9 for non-residential small general service customers, hereafter referred to as "small general services customers") and meets the customer's energy and capacity needs instantaneously whenever the customer's generation resource is not able to meet those needs behind the meter.

The Current NEM Program further provides for the customer to 'bank' those kWhs they exported to their utility and use them to offset consumption at other times. "Banking" refers to virtual storage that is a by-product of NEM program design and does not represent actual physical storage of the customer's generation. However, NEM ratemaking tools that permit a banking product result in customers receiving the same financial benefits by artificially giving them the benefit of physical storage for their exports. Specifically, consider an example where a customer generates 3 kWh at 1pm in January and consumes 1 kWh at 1pm and 2 kWh at 8pm that same day. In this example, the customer consumes 1 kWh of generation and exports the remaining 2 kWh to their utility at 1pm. The customer then uses the 2 kWh of exported energy to offset the 2 kWh delivered by the utility at 8pm. Since there is no associated storage device on either side of the meter, the customer is considered to have 'banked' the 2 kWh to offset the delivered energy. Therefore the customer was able to use all 3 kWh to cover their load and pay nothing for the 2 kWh delivered by the utility.

This is the primary distinction of an NEM program—the customer can "bank" a kWh generated but not used to offset behind the meter consumption and then use that 'banked' kWh to offset a kWh consumed at a different time within a "netting period." Netting is frequently used to describe this "banking" feature as it allows customers to "net" the total energy produced by the customer-generator against the customer's load during a prescribed period—hence the common use of the term "Net Energy Metering" to describe these types of programs.

Further, as noted above, "netting" allows customers to offset energy usage in hours when their generator is not operating, resulting in no payment to the utility for energy delivered because previous "banked" exports are used to offset that usage. Therefore, in this case, the compensation the customer is receiving for a kWh generated within the netting period is equal to the customer's retail rate.

The Current NEM Program allows yearly netting or, stated otherwise, "banking" for the year, regardless of whether energy produced off-peak is banked and then consumed during on-peak hours. Additionally, DESC's Current NEM Program compensates the customer for every kWh generated within the netting period at a rate equal to the customer's retail rate. For example, a customer may use a kWh generated and exported in April to first offset a kWh consumed in that month and, if exports exceed total April delivered load, that balance can also be 'banked' and used in June when exports are less than delivered load. For any 'banked' kWh not used to offset billed usage by year-end, DESC is then required to provide the customers with a bill credit equal to those banked kWhs at the utility's avoided cost rate, and the amount of banked kWh would reset to zero for the start of the upcoming year.

Q. HAVE YOU ANALYZED HOW AN AVERAGE CUSTOMER-GENERATOR'S CONSUMPTION LEVEL CHANGES OVER THE COURSE OF A YEAR?

A. Yes. I was able to develop hourly consumption patterns for both before and after installation of customer-generator system using the 2019 average hourly load consumption and generation data for NEM customers. Using this data, I then determined the hourly patterns for generation used by the customer behind the meter, as well as the remaining generation exported to the system.

Figures 1 and 2 below shows the average monthly consumption and net consumption (before and after self-consumption) for residential and small general service customers, respectively. The two areas together represent total consumption while the light grey represents load after the customer consumes generation behind the meter. The dark shaded area represents the amount of self-supplied generation consumed by the customer behind the meter. The darker area also represents the decrease in volumes that are applied to the current retail rate—creating significant bill savings to retail NEM customers—and the avoidance of fixed costs embedded in the volumetric retail rates, but are still properly attributed to these NEM customers.

Figure 1: Average NEM Residential Load Profiles

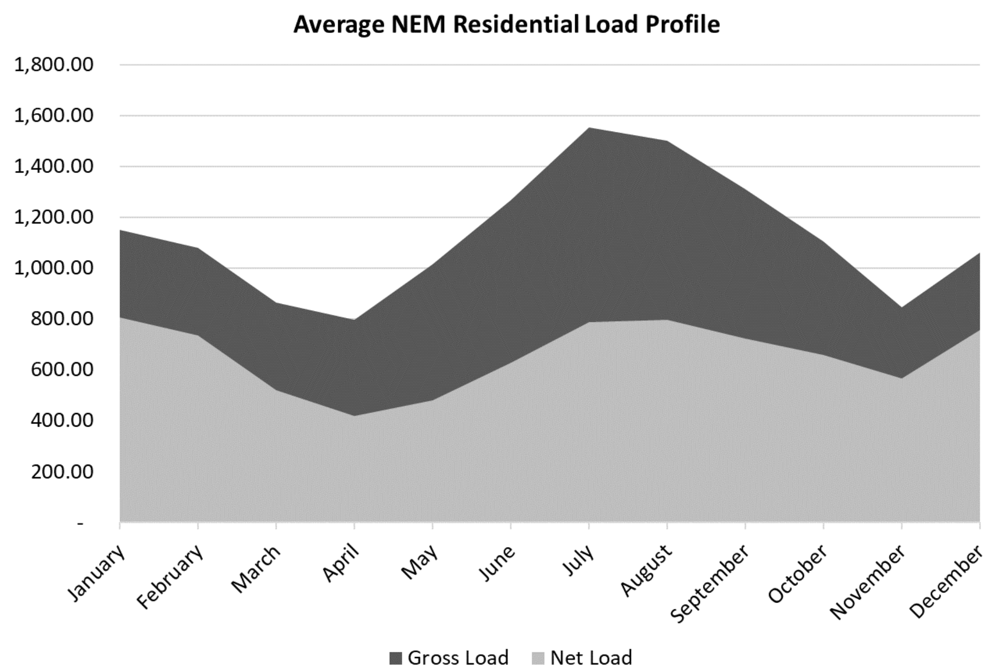
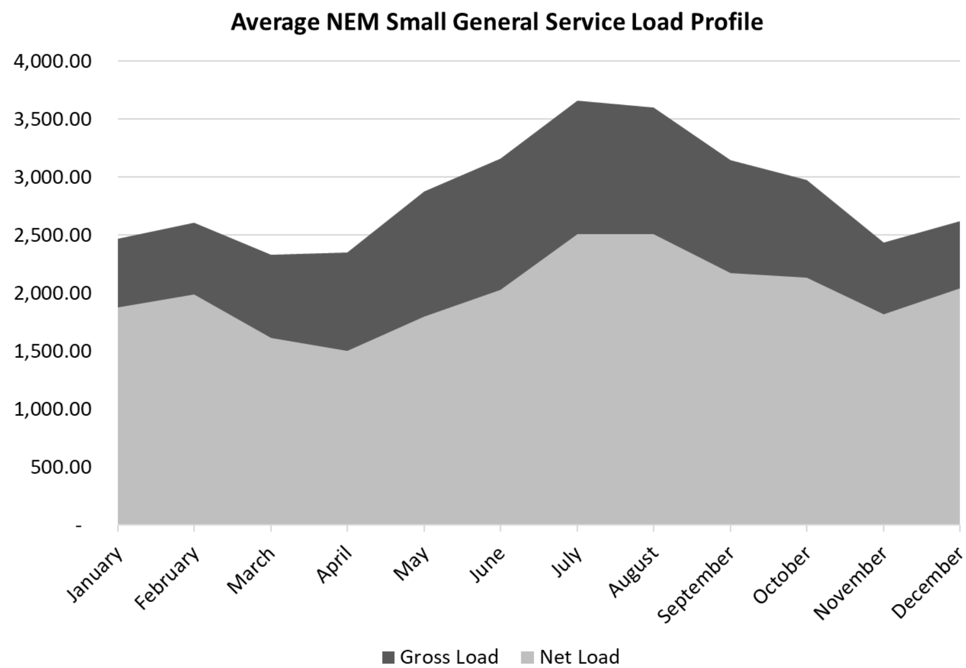


Figure 2: Average NEM Small General Service Load Profiles



Figures 3 and 4 below show the average monthly generation profile and the split between exports and self-consumption for residential and small general service customers, respectively. The sum of both areas is total generation, while the dark grey represents the amount of generation used by the customer. The light grey represents the amount of exports. Therefore, the light grey represents the energy that the NEM program "banks" for the customer-generator to use later to further reduce their bills beyond the savings from self-generation represented in Figure 1 and Figure 2.

Figure 3: Average NEM Residential Total Generation and Use Profiles

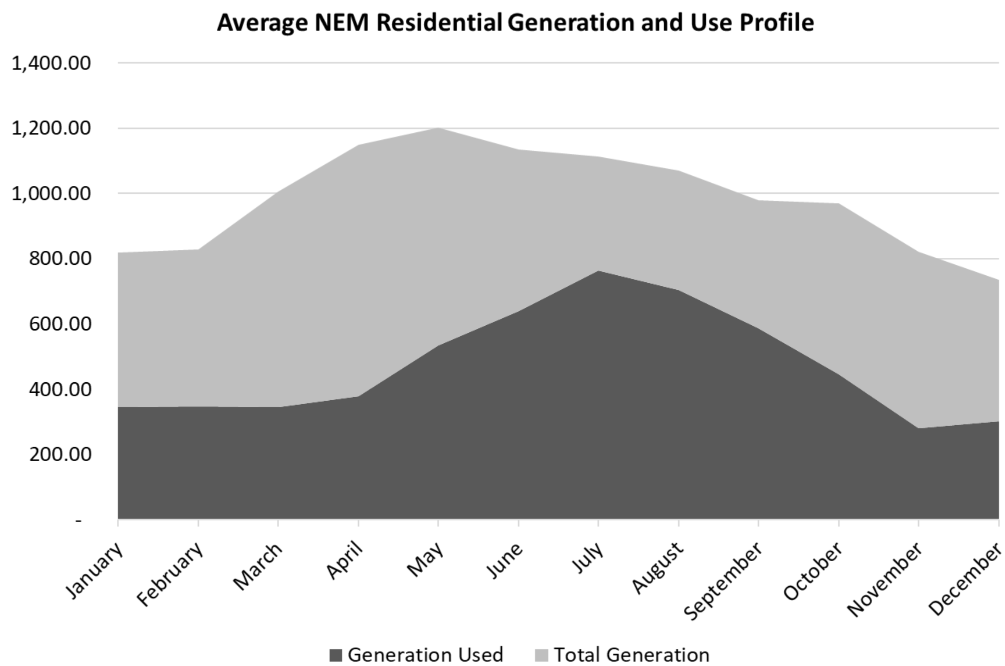
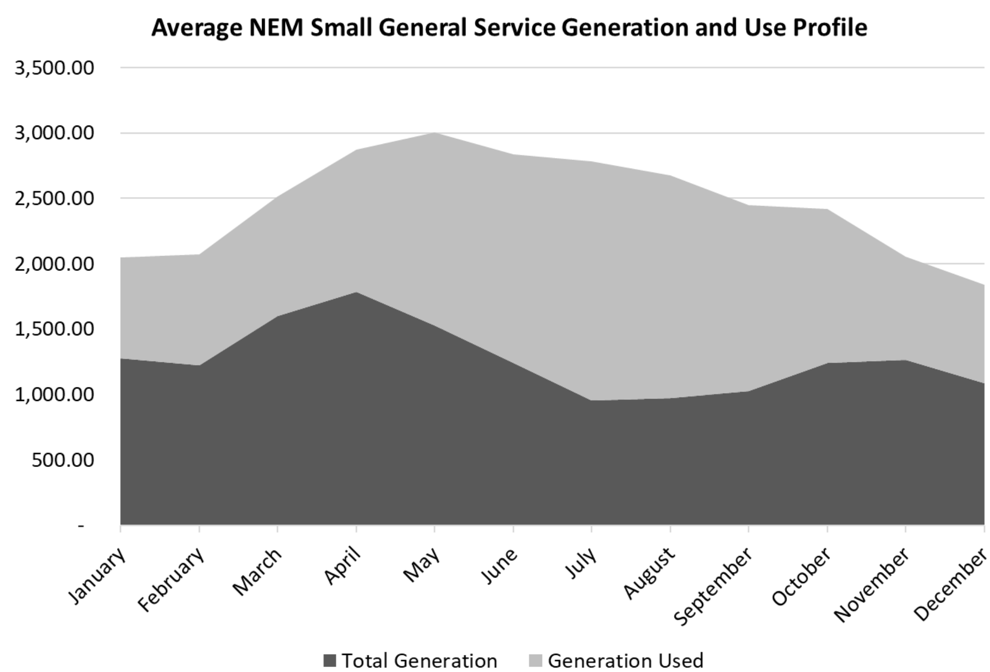


Figure 4: Average NEM Small General Service Generation and Use Profiles



Q. HAVE YOU COMPUTED THE AVERAGE BILL SAVINGS FOR A TYPICAL DESC NEM CUSTOMER?

A. Yes. To determine bill savings, I had to calculate a typical customer bill before and after installation of the customer-generation system. To do this, I also needed to reflect the current rate structures relative to the monthly usage patterns. Specifically, current rate structures for most NEM customers involves 'Block' or tiered rates whereby a customer pays a certain rate for consumption up to a certain level (Block 1) and a different rate for all consumption above that level (Block 2). Therefore, I needed to compute monthly consumption by each block to accurately calculate the customer bill before installation.

Using the average system size for the customer group and the hourly customer usage and generation profile data, I matched up hourly loads with hourly generation to calculate the amount of energy used hourly by the customer behind the meter and the amount of generation exported. Using the exported data, I then applied an algorithm to mimic the yearly netting scheme of the Current NEM Program to estimate the monthly billed energy. Finally, I calculated a monthly bill using current Block rates against the net monthly billed energy and then comparing that post installation bill with the pre-installation bill.

Tables 2 and 3 shows these calculations by month and the annual summations by residential and small general service customers, respectively. As Table 2 shows, the typical residential customer on NEM consumes about 13,544 kWh a year. These customers also typically install a 7.2 kW system that generates 11,823 kWh. These customers then consume of 5,675 kWh of that energy behind the meter such that total consumption from DESC is reduced to 7,869 kWh. The balance of generation of 6,148 kWh is then exported to the grid and "banked". Because these customer's total annual consumption is greater than the total generated, these customers can use all the generation to offset load.

The bill comparison in Table 2 shows that, without a customer-generation system, that customer would pay an annual bill of $1,660. After both savings from self-consumption and "banking", the NEM customer's annual bill is reduced to $310 from $1,660 for an annual bill savings of $1,350.

Table 3 shows this same information for small general service customers. Specifically, the typical small general service customer on NEM consumes about 34,228 kWh a year. These customers also typically install an 18 kW system that generates 29,558 kWh. These customers then consume of 14,367 kWh of that energy behind the meter such that total consumption from DESC is reduced to 19,861 kWh. The balance of generation of 15,190 kWh is then exported to the grid and "banked." Like residential customers, because these customer's total annual consumption is greater than the total generated, these customers can use all the generation to offset load.

The bill comparison in Table 3 shows that, without a customer-generation system, that customer would pay an annual bill of $4,120. After both savings from self-consumption and “banking”, the NEM customer’s annual bill is reduced to $815 from $4,120 for an annual bill savings of $3,305.

Table 2: Calculation of Customer Bills Before and After Installation – Residential

		A	B	C	D	E	F	G	H	I	J	K	L	M
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	Household Consumption	1,151	1,080	863	796	1,013	1,267	1,552	1,502	1,310	1,103	847	1,059	13,544
2	Tier 1 Usage	800	800	800	796	800	800	800	800	800	800	800	800	9,596
3	Tier 2 Usage	351	280	63	-	213	467	752	702	510	303	47	259	3,947
4	Tier 1 Rate (₵/kWh)	11.246	11.246	11.246	11.246	11.246	11.246	11.246	11.246	11.246	11.246	11.246	11.246	
5	Tier 2 Rate (₵/kWh)	10.788	10.788	10.788	10.788	10.788	12.395	12.395	12.395	12.395	10.788	10.788	10.788	
6	Customer Bill w/o NEM*	$138	$130	$106	$99	$123	$158	$193	$187	$163	$132	$105	$128	$1,660
7	Solar Generation	818	828	1,005	1,149	1,201	1,135	1,113	1,071	979	968	821	735	11,823
8	Solar Sent to Grid	472	481	661	770	667	495	349	366	392	522	539	433	6,148
9	Solar Used by BTM	346	346	344	379	534	640	764	705	587	446	281	302	5,675
10	Energy From DESC	805	733	519	417	479	627	788	797	723	657	566	757	7,869
11	Monthly Netted Energy	333	252	-	-	-	133	439	431	331	135	26	324	2,404
12	Tier 1 Usage	308	220	-	-	-	133	439	431	331	135	26	297	2,320
13	Tier 2 Usage	24	32	-	-	-	-	-	-	-	-	-	27	83
14	Annual Banked kWh													
15	Bank Balance	-	-	142	495	683	550	112	-	-	-	-	-	1,981
16	Bank Used	-	-	-	-	-	133	439	112	-	-	-	-	683
17	Billed kWh	333	252	-	-	-	0	0	320	331	135	26	324	1,721
18	Tier 1 Usage	333	252	-	-	-	0	0	320	331	135	26	324	1,721
19	Tier 2 Usage	-	-	-	-	-	-	-	-	-	-	-	-	
20	Customer Bill w NEM*	$47	$38	$10	$10	$10	$10	$10	$46	$47	$25	$13	$46	$311
21	Bill Savings	$90	$92	$97	$90	$113	$148	$183	$141	$116	$108	$92	$81	$1,359

*Includes $9.69 monthly customer charge

Table 3: Calculation of Customer Bills Before and After Installation – Small General Service

		A	B	C	D	E	F	G	H	I	J	K	L	M
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	Household Consumption	2,466	2,609	2,329	2,352	2,875	3,159	3,660	3,599	3,144	2,976	2,438	2,621	34,228
2	Tier 1 Usage	2,466	2,609	2,329	2,352	2,875	3,000	3,000	3,000	3,000	2,976	2,438	2,621	32,666
3	Tier 2 Usage	-	-	-	-	-	159	660	599	144	-	-	-	1,562
4	Tier 1 Rate (₵/kWh)	11.142	11.142	11.142	11.142	11.142	11.142	11.142	11.142	11.142	11.142	11.142	11.142	
5	Tier 2 Rate (₵/kWh)	10.365	10.365	10.365	10.365	10.365	11.863	11.863	11.863	11.863	10.365	10.365	10.365	
6	Customer Bill w/o NEM*	$299	$315	$284	$287	$345	$378	$437	$430	$376	$356	$296	$317	$4,120
7	Solar Generation	2,046	2,070	2,513	2,873	3,003	2,837	2,783	2,676	2,447	2,421	2,052	1,838	29,558
8	Solar Sent to Grid	1,277	1,224	1,598	1,784	1,525	1,241	956	970	1,023	1,239	1,266	1,088	15,198
9	Solar Used by BTM	769	845	915	1,089	1,478	1,596	1,827	1,707	1,424	1,182	786	749	14,367
10	Energy From DESC	1,697	1,764	1,414	1,263	1,397	1,562	1,833	1,893	1,719	1,795	1,652	1,872	19,861
11	Monthly Netted Energy	420	539	-	-	-	322	877	923	696	556	387	784	5,503
12	Tier 1 Usage	359	459	-	-	-	322	877	923	696	556	387	716	5,295
13	Tier 2 Usage	61	80	-	-	-	-	-	-	-	-	-	68	209
14	Annual Banked kWh													
15	Bank Balance	-	-	184	704	833	511	-	-	-	-	-	-	2,233
16	Bank Used	-	-	-	-	-	322	511	-	-	-	-	-	833
17	Billed kWh	420	539	-	-	-	-	366	923	696	556	387	784	4,670
18	Tier 1 Usage	420	539	-	-	-	-	366	923	696	556	387	784	4,670
19	Tier 2 Usage	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Customer Bill w NEM*	$71	$85	$25	$25	$25	$25	$65	$127	$102	$87	$68	$112	$815
21	Bill Savings	$228	$231	$259	$262	$320	$353	$372	$303	$274	$270	$229	$205	$3,305

*Includes $24.57 monthly customer charge

Q. DOES THE CURRENT NEM STRUCTURE CREATE NEGATIVE CONSEQUENCES FOR NON-PARTICIPATING CUSTOMERS AND DESC?

A. Yes, the current NEM savings are significant for participating customers, but there are costs that are covered or incurred by customer-generators that are now being born by non-participating customers or DESC. These "cost shifts" result in higher rates for non-participating customers and potential lost revenues to DESC.

Q. HOW DO THESE COST SHIFTS ARISE?

A. There are two types of 'cost shifts' created by different factors that can create a significant burden to non-participating customers. These two types can be summarized as "Banking" cost shift and "Rate Design" cost shift. "Rate Design" cost shifts are associated with behind the meter self-consumption and relate to the avoidance of fixed costs that are placed in volumetric rates. "Banking" cost shift describes cost shift that results from exports being valued higher than the benefit of the generation. I will describe each in greater detail below.

Q. PLEASE DESCRIBE THE "BANKING" COST SHIFT THAT IS ASSOCIATED WITH CUSTOMER-GENERATORS EXPORTING EXCESS POWER TO DESC.

A. As I described above, NEM programs offer "banking" of kWhs, also known as netting, that allows customers to use kWhs they generated and exported to DESC to offset kWhs they consume any time during the "netting period." Effectively DESC is "purchasing" the exported kWh and either delivering that kWh to another customer or to market, depending on need. This feature is a major contributor to the cost shift because under the Current NEM Program the price of the "purchased power" (export) is the customer' retail rate, which is greater than the cost DESC avoids by receiving the initial exported kWh (avoided costs), in some cases by a large margin.

Q. HAVE YOU QUANTIFIED THE MAGNITUDE OF THIS "BANKING" COST SHIFT?

A. Yes. As noted above, the typical NEM customer exports 6,148 kWh a year and uses that to offset load in other hours. Since the cumulative bill savings to the customer for netting is approximately $691 and the avoided cost of those exports is $216, the "Banking" cost shift, or $475.

As noted above, these same results for the typical NEM small general service customer on NEM. These customers export 15,190 kWh a year and net those kWh against customer use, creating bill savings of $1,693. The value of those exports is estimated to be $535, creating a "Banking" cost shift of $1,158 for this customer class.

Q. HOW DID YOU DETERMINE THE AVOIDED COSTS USED IN COMPUTING THE "BANKING" COST SHIFT FOR CURRENT NEM CUSTOMERS?

A. The avoided costs used in the estimates above were DESC's avoided costs based on the NEM Methodology values recently updated in Order No. 2020-244 as shown in Table 4.

Table 4: Current NEM Value Stack ($/kWh of Generation)

Components	Levelized Price ($/kWh)
Generation Costs	
Avoided Energy Costs	$0.02865[3] (a)
Avoided Capacity Costs	$0.00379 (a)
Ancillary Services	$0.0000 (a)
Avoided Criteria Pollutants	$0.00003 (a)
Avoided CO_2 Emission Cost	$0.00000 (a)
Fuel Hedge	$0.00000 (a)
Environmental Costs	$0.00105 (a)
Transmission and Distribution Costs	
T & D Capacity	$0.00000 (a)
Utility Integration & Interconnection Costs	($0.00096) (a)
Line Losses	$0.00266[4]
Administrative Costs	
Utility Administration Costs	$0.00000 (a)
Total	$0.03522 (a)

[3] Excludes Avoided Criteria Pollutants and Environmental Costs. Should also exclude Avoided CO2 Emissions Costs, but those values are currently set to zero.

[4] Currently based on 7.75% line losses.

(a) Excludes Line Losses

Q. WHAT RATE DESIGN TOOLS CAN BE USED TO REDUCE OR ELIMINATE THE "BANKING" COST SHIFT?

A. The most effective means for eliminating the "banking" cost shift is to provide a level of compensation to the customer-generator for the exported kWh that is as close to the avoided costs resulting from the delivered kWh as possible. Specifically, the export credit should be based on DESC's avoided costs and reflect any variability in these avoided costs based on time of day.

Q. PLEASE DESCRIBE THE "RATE DESIGN" COST SHIFT ASSOCIATED WITH BEHIND THE METER CONSUMPTION.

A. Rates are designed to collect all costs for a utility. These costs include both variable costs related to the production and delivery of a kWh and fixed costs that have been incurred in the past to ensure adequate capacity and other services (such as delivery) that the utility is required to provide.

The variable costs are considered avoidable if the utility saves costs when they do not need to deliver a kWh. Fixed costs, however, exist regardless of level of sales in each period. Finally, it is important to note that included in these 'fixed' costs are the returns allowed to the utility to compensate for the long-term capital investments made to ensure reliability and the appropriate level of customer service (e.g., transmission and generation capacity).

Rate design for residential and small general service customers is typically simplistic to facilitate customer understanding and provide bills that are easy to understand. These rate designs also incorporate numerous policy perspectives, such as creating signals to customers to consume less or reward customers who use very little electricity.

Therefore, for most residential and small general service customers, rates are predominately volumetric (cost per kWh) with a small, manageable monthly charge. As a result, volumetric rates include both variable and fixed costs. Further, if those volumetric rates are constant over time, then the rate may not represent the possible range in costs that vary by time or season.

Historically, volumetric rates have not been a problem because there is a high correlation between volumetric consumption (kWh) and overall capacity used (demand). Further, volumetric consumption typically drives variable rates while capacity drives fixed costs (e.g., fuel costs for a kWh versus capital for a plant to create generation capacity). However, if a customer uses less electricity but doesn't reduce their demand levels in kind—as in the case of NEM customers—this relationship breaks down. Customers who install customer-generation systems typically can greatly reduce their level of use but do not reduce their demand, especially if their peak demand occurs at times when the customer's generator is not operating.

The vast majority of DESC's residential and small general services customers on NEM have volumetric rates and thus do not pay the same level of fixed costs as similarly-sized customers without customer-generation systems. These fixed costs that are no longer collected from the NEM customer are shifted instead to non-NEM customers result in the "Rate Design" cost shift.

It should be noted that, for larger commercial and industrial customers, more complex rate designs are used which do not allow for these customers to avoid fixed costs. Therefore the "Rate Design" cost shift is already minimized for these customers.

Q. HAVE YOU QUANTIFIED THE MAGNITUDE OF THE "RATE DESIGN" COST SHIFT?

A. Yes. As noted above, the typical NEM customer consumes 5,675 kWh behind the meter every year, creating an average annual bill savings, at current rates, of approximately $659. Subtracting the avoided costs from the bill savings, which is estimated to be $200, the total "Rate Design" cost shift is $459.

Similarly, the typical NEM small general service customer on NEM self-consumes about 14,367 kWh behind the meter a year, creating bill savings of $1,612. The value of those exports is estimated to be $506, creating a "Rate Design" cost shift of $1,106 for this customer class.

Q. HOW DID YOU DETERMINE THIS LEVEL OF "RATE DESIGN" COST SHIFT FOR CURRENT NEM CUSTOMERS?

A. As noted above, I estimated the customer's bill savings and subtracted the total avoided cost of that generation consumed behind the meter. I determined the bill savings by estimating, by month, the amount of generation used by the customer and the resulting level of consumption served by DESC. I then computed the monthly bill savings using the current rates.[5]

I then estimated the total avoided costs of the generation by multiplying the amount of behind the meter self-consumption by the same avoided cost values I used for the "Banking" energy, that are consistent with the NEM Methodology.

Q. WHAT TECHNIQUES ARE USED ELIMINATE THE "RATE DESIGN" COST SHIFT?

A. As noted above, the key contributor to Rate Design cost shift under the Current NEM Program is that the rate design treats most costs as variable, blending both volumetric and fixed costs. Therefore, going forward, DESC has to implement rate mechanisms for Solar Choice customers that allow for the collection of fixed costs that are not tied to volumetric use, and thus not easily avoided with behind the meter consumption.

One common tool is a demand charge that changes only for a customer's peak use for a month and changes from month-to-month. This approach is limited because

[5] Note that, for the cost shift estimates provided, the "Rate Design" cost shift is assigned those Block 2 cost savings first, with remaining Block 2 cost offsets and any Block 1 offsets flowing to the "Banking" cost shift.

demand levels are also ‘volumetric’ in that the customer can change their demand levels and thus avoid fixed costs included in the demand charge.

Another rate design tool is a fixed charge per month. However, this technique is also limited because it does not vary by the size of the customer. This is problematic because customers who use more of the system should pay more towards those fixed charges.

It is possible, however, to create a fixed charge that varies by the size of the customer, for example connection size or, in the case of customer-generation, the size of the customer’s system. These mechanisms result in a ‘subscription’ type rate that both reflects the use of the grid by the customer and cannot be avoided.

As discussed above, “Rate Design” cost shift can also result from volumetric rates that don’t represent the variability in costs over time and season. Time of Use (“TOU”) rates go a long way in reflecting these costs and avoiding “Rate Design” cost shift as customers see different savings levels depending on whether they self-consume when variable costs are generally higher. TOU rates can and should be used in combination with one or more of the techniques listed above to fully address “Rate Design” cost shift.

Q. DID YOU QUANTIFY THE TOTAL LEVEL OF “BANKING” AND “RATE DESIGN” COST SHIFT FOR THE AVERAGE CUSTOMER CURRENTLY ON NEM?

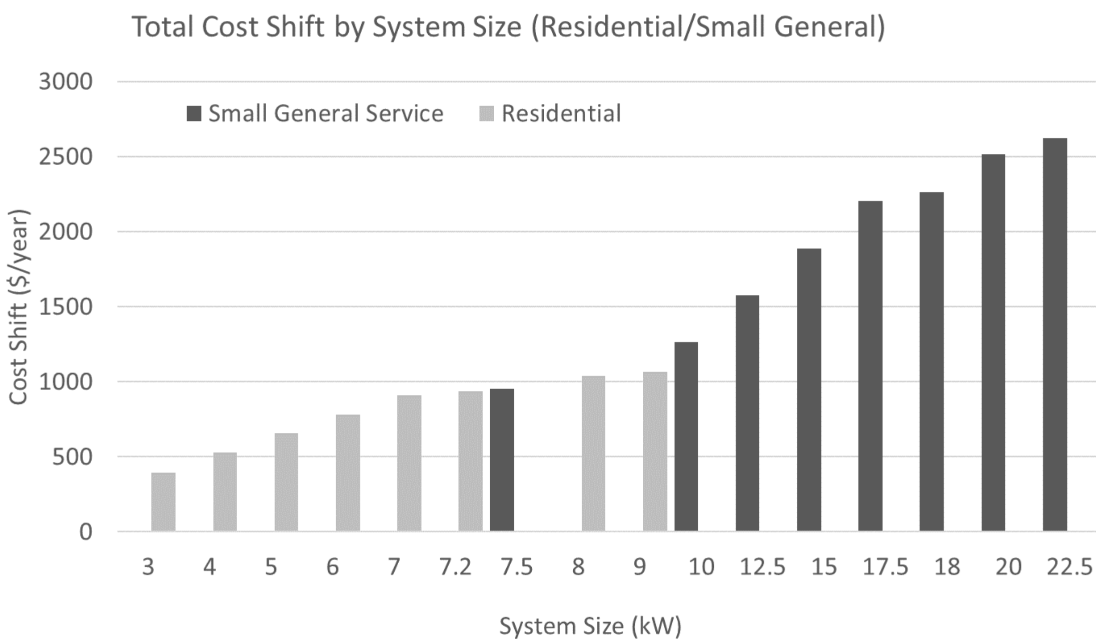
A. Yes. This value is simply the sum of the two. For residential it is $459 for the "Rate Design" cost shift plus $475 for "Banking" cost shift for a total cost shift of $934 per year. A simple check is to take the entire customer-generation output, or 11,823 kWh times the avoided costs, or $0.03522 to compute total value of the generation at $416. I can then subtract this from the customers total bill savings of $1,350 and get a cost shift of $934.

For small general services it is $1,106 for the "Rate Design" cost shift plus $1,158 for "Banking" cost shift for a total cost shift of $2,264 per year. A simple check is to take the entire customer-generation output, or 29,558 kWh times the avoided costs, or $0.03522 to compute total value of the generation at $1,041. I can then subtract this from the customers total bill savings of $3,305 and get a cost shift of $2,264.

Q. DOES THE SIZE OF THE CUSTOMER-GENERATION SYSTEM EXACERBATE THESE COST SHIFTS?

A. Absolutely. If a customer installs a system that is closer to the size of their peak use, then more of the energy generated is capable of being exported, increasing the size of the "banking" cost shift. Figure 5 below shows how the "Banking" and "Rate Design" cost shifts—as well as the total cost shift—changes for a customer that consumes the same amount the size of the generation system changes. Figure 5 shows the cost shifts and the variability in this cost shift based on size of system.

Figure 5: Cost Shift by Size of System



SOLAR CHOICE TARIFFS

Q. PLEASE DESCRIBE DESC'S KEY CONSIDERATIONS WHEN DESIGNING THE SOLAR CHOICE TARIFFS.

A. Consistent with what I presented in my Responsive Testimony in the Generic Docket, DESC considered the five following steps in developing the Solar Choice Tariffs:

1. Fully determine costs and benefits of groups of customers;
2. Allocate those costs to those customers;
3. Determine whether the further segmentation of customers according to their contribution to these costs and benefits was needed;
4. Design rates to charge customers for the costs they create; and
5. Create incentives to credit customers for the benefits they create.

The proposed rate structure was developed based on these considerations. I will note that DESC decided to not pursue a separate customer class for this rate structure at this time. Further, after reviewing the rate structures and NEM for all customers classes, it was determined that only residential and small general service customer rate structures needed to be re-designed. With medium and large general service customers, the "Banking" cost shift was minimal because these customers generally consume most of the generation they create, and the "Rate Design" cost shift was minimal because these customers are usually on more complex demand charge rates that better reflect cost of service.

Q. PLEASE DESCRIBE THE PROPOSED RATE DESIGN IN THE SOLAR CHOICE TARIFFS.

A. Figure 6 shows a diagram of the rate designs in the Solar Choice Tariffs. DESC is proposing a Solar Choice Subscription Rate for Residential (Rate 8) and Small General Services (Rate 9).

As Figure 6 shows, the rate consists of six features:

1. The customer installs a system and can consume generation behind the meter without penalty.
2. DESC continues to provide load serving services for the customer's needs whenever the customer's generation system is not fully meeting the customer's load requirements.

3. The customer pays time differentiated (TOU) rates for all power delivered by DESC.
4. The customer is able to export any excess generation to DESC.
5. The customer receives an export credit for that generation provided to DESC.
6. The customer pays a monthly ‘Subscription’ to cover fixed costs associated with the services provide by DESC and includes a credit for the reduced cost of service resulting from the customer consuming energy behind the meter.

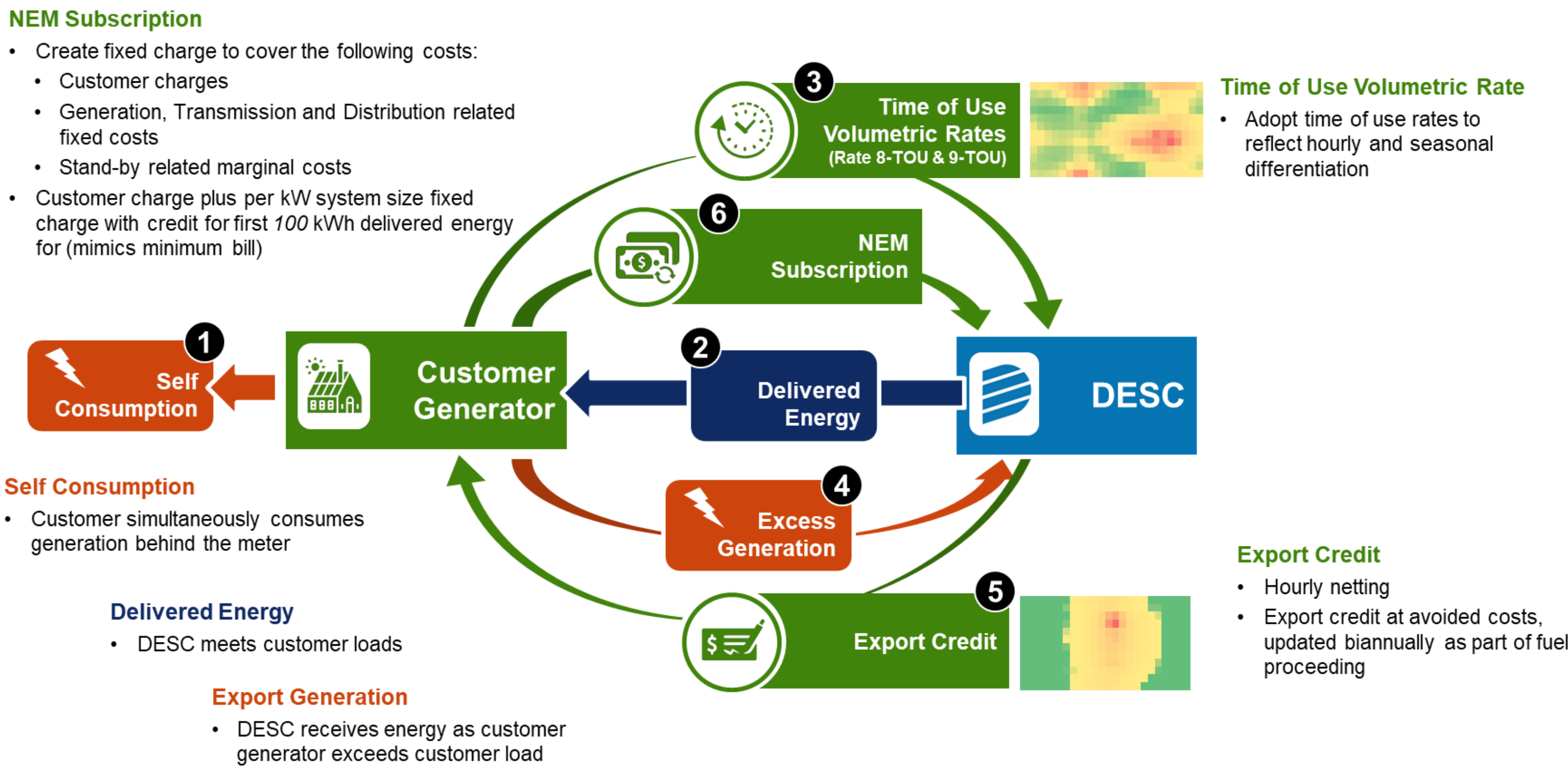
Q. PLEASE DESCRIBE THE MECHANICS OF DEVELOPING THE VALUES IN THE SOLAR CHOICE TARIFFS.

A. I utilized the following stepwise process:

1. Determined the revenue requirement that must be collected to ensure a ‘revenue neutral’ rate design that results in the average NEM customer paying the same amount annually as they would under their current rate, *prior to installing generation system*.
2. Categorized the revenue requirement first into to rate components to segment by function (e.g., production, transmission etc) and then by fixed, variable or time differentiated.
3. Identified appropriate rate mechanisms to recover each of these rate components.

[remainder of page intentionally left blank]

Figure 6: Solar Choice Tariffs Rate Design



Q. HOW DID YOU DETERMINE THE REVENUE REQUIREMENT TO COMPUTE A 'REVENUE NEUTRAL' RATE?

A. As stated above, I had already calculated the NEM customer's average bill before installing a system as $1,660 and $4,120 for residential and small general service customers, respectively. This was the best representation of the cost to serve the NEM customer prior to installation of the system. Since these customers are installing generation that offsets use, it is then appropriate to subtract the avoided costs saved by their self-generation from these cost of service measurements. This required making an assumption about the minimum value of solar a customer is likely to install. Since this value can vary significantly, the most straight forward approach was to assume they would install a system that at least meets their demand. For residential this value was 3 kW while it was 2.5 times larger[6], or 7.5 kW for small generation.

Using the 2019 generation profiles discussed above, the generation from a 3kW system is estimated to be approximately 4,926 and a typical customer who consumes 13,544 would consume approximately 4,030 kWh, behind the meter. Applying time differentiated avoided costs from DESC's avoided cost that are embedded in the NEM Methodology, the value of this power is assumed to be

[6] Small general services customers have very similar load profiles, so it follows that the peak demand is roughly the same order of magnitude greater that residential as the energy consumed.

approximately $146. Therefore, the residential revenue requirement to collect with the new tariff was $1,515.[7]

For small general service, a 7.2 kW system generates approximately 12,316 kWh and a typical customer who consumes 34,228 kWh would consume approximately 10,241 kWh behind the meter. Again, applying time differentiated avoided costs from DESC's avoided cost that are embedded in the NEM Methodology, the value of this power is assumed to be approximately $370. Therefore, the residential revenue requirement to collect with the new tariff was $3,750.

Q. HOW DID YOU CATEGORIZE THESE REVENUE REQUIREMENTS?

A. I first segmented them into six functional categories currently included in Docket No. 2020-125-E:

1. Customer Costs
2. Energy Costs
3. Production Cost
4. Transmission Costs
5. Distribution Costs
6. Avoided Cost Benefit.

[7] Slight differences due to rounding error.

For customer charges, I used the current customer cost per unit for residential and commercial proposed in Docket No. 2020-125-E: $19.49 and $32.50 per month respectively. To compute the annual revenue requirement from the Basic Facilities Charge ("BFC"), I multiplied these values by 12 months. For Energy, Production, Transmission, and Distribution categories, I used DESC's unit cost tables from Docket No. 2020-125-E and developed allocation factors of the remaining costs to these four categories.

Finally, I distinguished between variable and fixed. Fixed customer costs are driven by the number of customers. Energy costs are almost exclusively variable and driven by energy (kWh) consumption. Transmission and Distribution costs are generally fixed but do vary based on size of the customer. Lastly, Production costs include both fixed and variable costs.

To further segment Production costs, I designated a portion of the Production costs as 'variable' by using the ratio of marginal costs to total costs, designating the remaining Production costs as fixed. To calculate this ratio, I used the most recent estimate of capacity avoided costs used in NEM Methodology and dividing that by the total unit cost per kW of production costs from the unit cost table. This yields a percentage of about 70%. Therefore, I assigned 70% of the production costs to variable and the remainder to fixed.

Lastly, for Avoided Cost Benefits I used the avoided cost estimates noted above for the minimum system sizes calculated above: $146 and $370 for residential and small general services respectively.

Table 5 shows the results of this allocation including the designation of fixed or variable under header of 'Type'.

Table 5: Breakdown of Costs for Each Rate Component

		Residential		Commercial	
	Type	Percent	Costs	Percent	Costs
Customer Costs	Fixed per Customer		234		390
Total Less Customer			1,427		3,730
Energy Costs	Variable by kWh	29%	415	29%	1,069
Production Costs - Marginal	Variable by kWh	33%	470	32%	1,195
Production Costs - Fixed	Fixed	14%	203	14%	515
Transmission Costs	Fixed	11%	154	11%	424
Distribution Costs	Fixed	13%	185	14%	527
Subtotal			1,660		4,120
Avoided Cost Benefit	Fixed by size of system		(146)		(370)
Total			1,515		3,750

Q. HOW DID YOU DETERMINE THE RATE MECHANISM TO COLLECT THE REVENUE REQUIREMENT IN EACH OF THESE CATEGORIES OF COSTS?

A. I used common rate designs for the types of costs as follows:

- **Customer Costs** are fixed costs that are driven by number of customers, therefore rate mechanism is a fixed per month charge.

- **Energy Costs** are variable costs that are driven by energy usage; therefore, the rate mechanism is a variable per kWh charge. I also recognized that the energy costs vary by time of day, thus I noted that this volumetric charge should be time differentiated.
- **Production Costs** include both fixed and variable cost and result from generation. For those costs designated as variable, I recognized that these costs are best collected using time differentiated volumetric charges. For those fixed costs, I utilized a constant volumetric charge (one that does not vary with time of day or season).
- **Transmission Costs** are fixed costs but are indirectly influenced by customer size and should not be avoided by changes in customer behavior. Thus, these costs should be collected through a subscription charge that reflects the Transmission System impact of the customer generator. **Distribution Costs** are similar to transmission, these are fixed costs but are indirectly influenced by customer size and should not be avoided by changes in customer behaviour. Thus, these costs should be collected through a subscription charge. Also, like transmission, this subscription should be based on customer generators impact to the Distribution system.
- **Avoided Benefits** are directly linked to the level of system size and not to a customer's net consumption, thus these costs should also be collected

in a subscription charge reflecting the benefits of customer generator on the system

The last step was to determine how to allocate costs across hours and choose appropriate time of use rates to collect the energy costs and 70% of the production costs. To do this. I created two allocation factors: Marginal Energy Cost Allocator and a Net Load Allocator. The Marginal Energy Cost Allocator was based on hourly customer loads for the customer class multiplied by the hourly marginal costs. The hourly loads from customer class were the same loads used in Tables 2 and 3 above and based on 2019 actual metered data for the two customer classes. The Net Load Allocator is based on DESC's net load which is total generation less renewables.

The Marginal Energy Cost Allocator is based upon hourly marginal costs and were computed by using actual 2019 marginal costs and then calibrating the price levels to DESC's 2022 forecasted marginal costs by month by hour. This creates a necessary level of volatility in marginal costs so that it can be seen in load in 2019 and calibrated to 2022 forecasted costs. I then multiplied these hourly loads by the marginal costs to develop a vector of costs to apply to the allocation method.

The Net Load Allocation factor was derived directly from the vector of 2019 net loads.

The allocators were then calculated as follows:

1. Rank the loads or costs from lowest to highest to create a 'load duration curve'.

2. Weight the incremental load or costs in each hour by calculating the difference in load in one hour against the load from the previous hour (the difference for the first, or lowest ranking hour, is set to the value for that hour). This difference is then weighted by number of hours divided by total hours. There are 8,760 hours in a year therefore this weight is 1/8760.

3. For each hour, sum weighted differences for that hour plus all hours before that hour (e.g., for hour 10 summed the differences of hours 1 through 10) to come up with a total weighted load or cost for that hour.

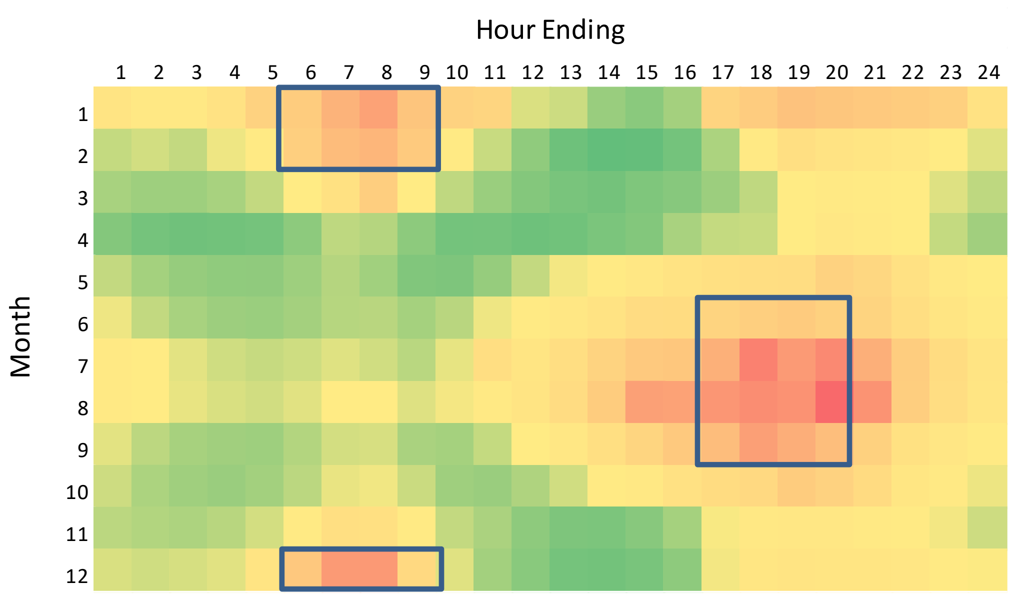
4. Finally, take the ratio of each hour's weight to the total of each hours weighted load to develop a final load or cost weighting that sums to 1.

I applied the Marginal Energy Cost Allocator factors to the Energy Costs to create an estimate of the marginal energy costs allocated to each hour. The Marginal Energy Cost Allocator factor is appropriate to apply to energy costs because those costs are mostly driven by changes in marginal costs.

Similarly, I applied the Net Load Allocator Factors to variable Production Costs to estimate the variable production costs by hour. The Net Load Allocator factor is appropriate for the variable Production Costs because production marginal costs are driven by capacity needs that are met by combined cycle generators and net load. This is the level of load planned to be met by these marginal capacity units.

After allocating costs I examined the average costs by hour and month (12x24) and examined the patterns of costs. Figure 7 shows the time differentiated heat map for residential. Using Figure 7, I visually determined groupings of hours to develop TOU periods, with the qualification that each TOU period should be four hours and occur over no less than three consecutive months. A four-hour peak, creates a large differential between peak and off-peak periods, which creates a greater incentive for customers to modify behavior for a manageable period of time.

Figure 7: Cost Variability Heat Map



The same TOU load allocation factors and periods were used for both residential and small general service customers. because the load shapes of these two customer classes, as shown in Tables 2 and 3are very similar

As a result of this review with these constraints, the TOU periods are as follows:

- Peak Summer; 4pm to 8pm June-Sept
- Peak Winter; 5am to 9am Dec-Feb.
- Off Peak – all other hours, including weekends (Saturday and Sunday) and holidays.

Q. HOW DID YOUR ANALYSIS OF THIS INFORMATION AFFECT YOUR CALCULATION OF THE AMOUNT OF REVENUE REQUIREMENT TO BE COLLECTED FROM EACH RATE COMPONENT?

A. As I summarized above, I ultimately defined four rate mechanisms and applied them differently across the various cost categories. The four mechanisms are a monthly charge, time differentiated volumetric charge, undifferentiated volumetric charge, and a subscription charge. Tables 6 and 7 show the final revenue requirement breakdowns by classification and rate component for residential and small general service customer groups.

Table 6: Revenue Requirement Categorization for Residential

		Volumetric TOU Rate						
	Customer Charge	**Winter Peak**	**Summer Peak**	**Off Peak**	**Total**	**Volumetric Flat**	**Subscription**	**Total**
Customer Costs	234							234
Energy Costs		67	93	255	415			415
Production Costs - Marginal		22	79	369	470			470

Production Costs - Fixed						203		203
Transmission Costs							154	154
Distribution Costs							185	185
Subtotal	234	89	172	624	885	203	339	1,660
Avoided Cost Benefit							(146)	(146)
Total							194	1,515

Table 7: Revenue Requirement Categorization for Small General Service

	Customer Charge	Volumetric TOU Rate Winter Peak	Summer Peak	Off Peak	Total	Volumetric Flat	Subscription	Total
Customer Costs	390							390
Energy Costs		172	240	656	1,069			1,069
Production Costs - Marginal		56	201	938	1,195			1,195
Production Costs - Fixed						515		515
Transmission Costs							424	424
Distribution Costs							527	527
Subtotal	390	228	441	1,594	2,263	515	951	4,120
Avoided Cost Benefit							(370)	(370)
Total							581	3,750

Q. PLEASE DESCRIBE HOW YOU DEVELOPED THE BFC IN THE SOLAR CHOICE TARIFFS.

A. The BFC recovers the revenue requirement needed to cover customer related costs as defined in DESC's current rate case Docket No. 2020-125-E. Specifically, this rate was set to the monthly BFC as proposed in that Docket, which is $19.50. This is computed as simply taking the revenue requirements in Tables 2 and 3 and dividing by the number of months in a year (12).

Q. PLEASE DESCRIBE HOW YOU DEVELOPED THE SUBSCRIPTION FEE IN THE SOLAR CHOICE TARIFFS.

A. The subscription is designed to collect costs based on the size of the customer's PV system because size of system has an impact on T&D systems and also reduces the amount of fixed costs that will be collected. Therefore using a subscription fee based on size of system reduces rate design cost shift.

To ensure the customer receives compensation for the benefit of self-consumption provided to the system, I then determined the avoided cost credit that should apply to customers for their self-generation and incorporate that benefit into the subscription rate. As I explained above, to do this, I had to make an assumption regarding the minimum system size. This benefit then reduces the level of the subscription rate and ensures the rate is designed based on the decrease in the cost to serve from the customer's consumption of generation.

To ensure all costs are collected, I then determined an equivalent minimum subscription to ensure full collection of these costs. The minimum subscription should include taking the subscription rate and applying the same minimum system size I used for the benefit charge, or 3 kW for residential and 7.5 kW for small general services.

Table 8 shows the calculation of the subscription rate.

Table 8: Calculation of Subscription Rate

	A	B	C	D=B*C	E=A/D
	Revenue Requirement ($)	**Minimum System Size (kW)**	**Months**	**Billing Determinant**	**Rate ($/kW)**
Residential	$193	3	12	36	$5.36
Small General Services	$581	7.5	12	90	$6.46

To create a more customer friendly rate the rate was rounded to the nearest $.10 ($5.40 and $6.50) and calibrated the volumetric rates to ensure appropriate collection of revenue requirement.

Q. ARE YOU PROPOSING A MINIMUM SUBSCRIPTION LEVEL?

A. Yes. The final rate design calls for a minimum subscription level to ensure collection of all transmission and distribution costs. This minimum is $16.20 for residential and reflects a minimum system size of 3 kW. Similarly, there is a minimum bill of $48.75 for small general services that equates to the $6.50 times the 7.5 kW. Table 9 shows this calculation.

Table 9: Calculation of Minimum Subscription

	A	B	C=A*B
	Rate ($/kW)	**Minimum System Size (kW)**	**Rate ($/month)**
Residential	$5.40	3	$16.20
Small General Services	$6.50	7.5	$48.75

Q. PLEASE EXPLAIN HOW YOU DEVELOPED THE TOU RATES IN THE SOLAR CHOICE TARIFFS.

A. As I discuss above, costs were allocated by hour using the Marginal Cost and Net Load allocation factors. Summing those allocation factors by TOU period allowed for estimation of the level of revenue requirement to collect from each TOU period. These are shown in Table 10. To compute the rate, I needed to estimate the number of kWh in each TOU period. Using the 2019 load profiles before system implementation, I was able to develop the ratio of time of use period kWh to total kWh for each period. I then use these factors and apply to the total average energy use of the customer classes to determine the number of kWh in each period to use in the calculation of the rate for that period. Table 10 shows this calculation.

Table 10: TOU Rates by Class

	Winter Peak	Summer Peak	Off-Peak	Total	Flat
Load Allocation	3.87%	8.34%	87.79%	100.00%	
Load					
Residential	524	1,129	11,891	13,544	13,544
Small General Service	1,324	2,854	30,050	34,228	34,228
Costs					
Residential	89	172	624	885	203
Small General Service	228	441	1,594	2,263	515
TOU Rates	**Winter Peak**	**Summer Peak**	**Off-Peak**	**FLAT**	
Residential	16.927	15.259	5.245		1.496
Small General Service	17.195	15.461	5.306		1.506
Volumetric Rates					
Residential	18.42	16.75	6.74		
Small General Service	18.69	16.96	6.80		

It should be noted that the final TOU rates include the 'flat' rate which represents a levelized value from the different times of use and is applied equally to all rates.

Q. PLEASE EXPLAIN HOW YOU DEVELOPED THE EXPORT CREDIT COMPONENT.

A. The export rate is based on DESC's stated time differentiated avoided costs paid to utility-scale generators but averaged to the same time of use periods as the Solar Choice Subscription rate. These averages are based on the actual generation levels from the customer-generation systems for each Solar Choice Tariff TOU period. The residential and small general services customer generation profiles are very similar. Therefore, as Table 11 shows, the time differentiated export rates for residential and small general services are the same.

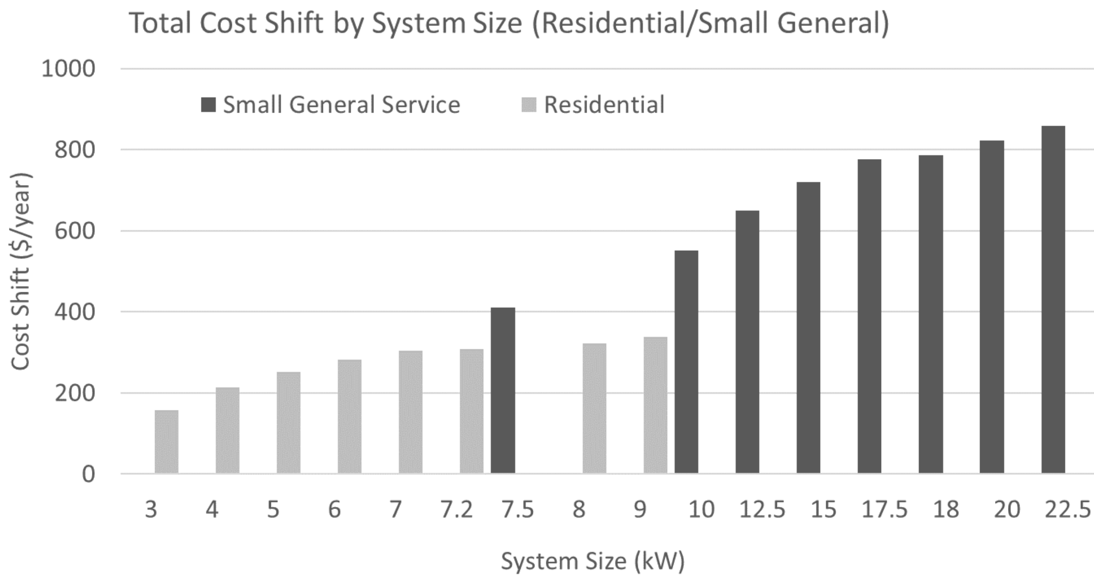
Table 11: TOU Rates by Class

	Residential	Small General Service
Winter Peak	3.796	3.796
Summer Peak	3.651	3.651
Off-Peak	3.622	3.622

Q. DID YOU QUANTIFY ANY REMAINING COST SHIFT THAT IS NOT ELIMINATED BY THE SOLAR CHOICE TARIFFS?

A. Yes. The "Banking" cost shift is eliminated. The only remaining cost shift is due to "Rate Design" cost shift although a significant portion of the current "Rate Design" cost shift has been reduced. Figure 8 shows the cost shift resulting from the Solar Choice Subscription Rate.

Figure 8: Total Cost Shift by System Size



As Figure 8 shows, the cost shift is continuing and does increase with size of system, but the increase slows as the output of each system approaches the customer's total energy use. This is because the rate structure continues to ensure that these fixed costs are collected even as the customer increases the generation to match their total load (e.g., total customer load equals total customer generation, which is where a customer's bill under current NEM tariff would approach zero).

Q. DOES ACT 62 ENVISION THAT A CERTAIN AMOUNT OF COST SHIFT MAY BE PERMISSIBLE UNDER THESE PROGRAMS?

A. Yes. Act 62 requires the elimination of the cost shift "to the greatest extent practicable."[8] It is virtually impossible to eliminate a "Rate Design" cost shift because rates are always designed to be revenue neutral for the average customer who is on that rate prior to installing the system. In other words, unless customer-generators are designated as a separate customer class and all costs to serve that customer are directly attributed to that customer class, there is the possibility of some cost shift. To design a rate with no cost shift, the rate would have to be based on the average customer's load after installation of generation, which is highly dependent upon the potential size of systems.

The Solar Choice Subscription rate represents a midpoint where customers benefit from installing systems while reducing cost shift to the greatest extent practicable.

Q. DO THE SOLAR CHOICE TARIFFS ALLOW FOR THE CUSTOMER TO USE GENERATED ENERGY BEHIND THE METER WITHOUT PENALTY IN ACCORDANCE WITH ACT 62?

A. Yes. The customer can consume self-generation energy behind the meter to fully offset their purchases from the utility just as they presently do under the Current NEM Program.

[8] S.C. Code Ann. § 58-40-20(G)(1).

Q. DOES THE SUBSCRIPTION RATE WITHIN THE SOLAR CHOICE TARIFFS CREATE A PENALTY IN VIOLATION OF ACT 62?

A. No. I want to clarify and emphasize that a subscription is not a penalty for several reasons. First, as noted above, the subscription is designed so the customer does not avoid paying these fixed costs that are attributable to all Solar Choice customers. These fixed costs are incurred to serve these customers, particularly for reliability of capacity for supply and delivery, and cannot be avoided.

Second, the subscription includes the value of the self-generation as a credit against these fixed costs. As explained above, this credit is based on a minimum system size (3 kW for residential and 7.5 kW for small general service).

In closing, it is critical to remember that charges to customer-generators that are unique to that group of customers are not a penalty if, as noted above, those charges are designed to collect the customer's cost of service. This is a common practice in rate design.

Q. ARE THERE BENEFITS TO DESC'S NON-PARTICIPATING CUSTOMERS THAT ARISE FROM THE SOLAR CHOICE TARIFFS?

A. Absolutely. First, as noted above, it greatly reduces both cost shifts, moderating the rate impacts to non-participates that they experience under the current NEM program.

Second, given the large price differentials in the TOU rates included in this tariff, customer-generators can create additional value options by encouraging adoption of emerging technologies, such as storage, advancing innovation and adoption of these promising technologies. Specifically, the vast majority of kWh exported are during the 'off-peak' power, given the timing of generation and level of customer consumption during the peak periods. If a customer is able to use storage to save energy from their system created during the off-peak period and use that energy during the peak period, customers can save between 12 and 14 cents a kWh, essentially offsetting all peak energy with solar production with storage. This has benefits for both customer-generators and DESC as costs are saved by both parties when costs are highest.

Further, this rate design allows for storage innovation coupled with solar without creating additional "Rate Design" cost shifts. Specifically, the difference between peak and off-peak rates creates a financial gain from storing off peak energy to be used during the peak. Lastly, this rate design sends the correct price signals to customers to size their systems to optimize value for both themselves and non-participating customers.

Q. HOW DO THE SOLAR CHOICE TARIFFS RESULT IN A METHODOLOGY TO COMPENSATE CUSTOMER-GENERATORS FOR

THE BENEFITS TO THE POWER SYSTEM PROVIDED BY THEIR GENERATION?

A. Customers are benefited in two ways. First, the rate is designed incorporating the benefits of the customer's self-consumption. As I explained above, the subscription includes the value of the self-generation as a credit in the subscription and thus scales with the size of the system as does the subscription. Second, the customer receives the value of solar for all exports, which is based on the Commission-approved avoided cost rates which reflects the benefits to DESC's for not incurring costs to generate that exported kWh.

Q. PLEASE DISCUSS HOW THE SOLAR CHOICE TARIFFS INCORPORATE BEST-PRACTICES FROM OTHER JURISDICTIONS.

A. The Solar Choice Tariffs incorporate several best-practices from other jurisdictions, and many of which were presented to the Commission in the Generic Docket. These best-practices include:

- TOU rates. Many utilities have moved to mandatory TOU, even while maintaining a NEM Rate structures.
- Net Billing. Customers experience a separate credit for exports and continue to pay retail rates for all energy consumed like all customers without customer-generators. The Solar Choice Tariffs not only provide

compensation for exports, but the export rates are based on the varying value of energy by the same TOU periods for customer load rates.

- Increased fixed charges or minimum bills. The minimum subscription serves as a minimum bill requiring all Solar Choice customers to pay a certain amount, regardless of the amount of self-consumption. It should be noted that an added benefit of the subscription is that customers continue to receive bill credits for all exports and the subscription includes the value of self-generation. Therefore, unlike other minimum bill structures Solar Choice customers are ensured compensation for the benefits that their generation provides to the DESC system, as required by Act 62.

Although the Solar Choice Tariffs employ many best practices, the subscription rate is one rate component within the tariffs that is increasingly viewed within the industry as an innovative ratemaking tool.

Q. SHOULD THE RATE DESIGNS WITHIN THE SOLAR CHOICE TARIFFS BE CONSISTENT ACROSS ALL SOUTH CAROLINA UTILITIES?

A. No, because any rate design should reflect each system and its unique load profile, generation mix, planning requirements, and customer needs. Second, there are multiple paths to achieve similar results that can utilized in various combinations to address a utility's unique objectives and, as noted above, its unique service territory and generation fleet profile.

Further, there are additional benefits to having different rate structures within South Carolina. to allow for further innovation in rate design for DERs in South Carolina. There are certain fundamentals in rate design that should apply to both utilities and do in DESC's Solar Choice Subscription rate.

Q. PLEASE EXPLAIN THE INTERDEPENDENCY OF THE VARIOUS RATE-MAKING TOOLS UTILIZED IN THE SOLAR CHOICE TARIFFS.

A. Rate design is an exercise in balancing multiple considerations and, in the end, reflects several trade-offs and design choices that all work together to form a holistic rate that achieves these multiple objectives. In short, the rate design is a zero-sum game and the designated revenue requirement to be collected to generate a revenue neutral rate must still be collected regardless of rate design choices. Therefore, small modifications to any rate component, such as the level of subscription or adjustment of TOU periods, will ultimately impact other rate components. Therefore, these rates work in conjunction to ensure that the costs to serve NEM customers—such as customer charges and transmission and distribution costs—are accurately captured in the rates to serve such customers. Any change to one component would then also modify the net effect of the tariffs, including the cost-shift and allocation of the costs and benefits under the tariffs.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.